Gas Distribution Pipeline Integrity Management

Enforcement Guidance

49 CFR Part 192 – Subpart P

Introduction

The materials contained in this document consist of guidance, techniques, procedures and other information for internal use by the PHMSA pipeline safety enforcement staff. This guidance document describes the practices used by PHMSA pipeline safety investigators and other enforcement personnel in undertaking their compliance, inspection, and enforcement activities. This document is U.S. Government property and is to be used in conjunction with official duties.

The Federal pipeline safety regulations (49 CFR Parts 190-199) discussed in this guidance document contains legally binding requirements. This document is not a regulation and creates no new legal obligations. The regulation is controlling. The materials in this document are explanatory in nature and reflect PHMSA's current application of the regulations in effect at the time of the issuance of the guidance. In preparing an enforcement action alleging a probable violation, an allegation must always be based on the failure to take a required action (or taking a prohibited action) that is set forth directly in the language of the regulation. An allegation should never be drafted in a manner that says the operator "violated the guidance."

Nothing in this guidance document is intended to diminish or otherwise affect the authority of PHMSA to carry out its statutory, regulatory or other official functions or to commit PHMSA to taking any action that is subject to its discretion. Nothing in this document is intended to and does not create any legal or equitable right or benefit, substantive or procedural, enforceable at law by any person or organization against PHMSA, its personnel, State agencies or officers carrying out programs authorized under Federal law.

Decisions about specific investigations and enforcement cases are made according to the specific facts and circumstances at hand. Investigations and compliance determinations often require careful legal and technical analysis of complicated issues. Although this guidance document serves as a reference for the staff responsible for investigations and enforcement, no set of procedures or policies can replace the need for active and ongoing consultation with supervisors, colleagues, and the Office of Chief Counsel in enforcement matters.

Comments and suggestions for future changes and additions to this guidance document are invited and should be forwarded to your supervisor.

The materials in this guidance document may be modified or revoked without prior notice by PHMSA management.

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For a complete “Glossary of Terms” please refer to the following link:

http://www.phmsa.dot.gov/staticfiles/PHMSA/Pipeline/TQGlossary/Glossary.html

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1001
Section Title	What definitions apply to this subpart?
Existing Code Language	The following definitions apply to this subpart: *Excavation Damage* means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility. *Hazardous Leak* means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous. *Integrity Management Plan or IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. *Integrity Management Program or IM Program* means an overall approach by an operator to ensure the integrity of its gas distribution system. *Mechanical fitting* means a mechanical device used to connect sections of pipe. The term "Mechanical fitting" applies only to: (1) Stab Type fittings; (2) Nut Follower Type fittings; (3) Bolted Type fittings; or (4) Other Compression Type fittings. *Small LPG Operator* means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, 76 FR 5494, February 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	
Guidance Information	1. A line does not have to experience a leak or release to be considered to have been damaged by excavation damage. 2. An operator need not classify leaks as hazardous or non-hazardous provided it repairs all leaks when found. To qualify for this exclusion, an operator must treat all leaks as if they were hazardous, providing for immediate repair or continuous action until the leak is repaired.
Examples of a Probable Violation	1. Operator does not have a comprehensive list of definitions. 2. Operator does not include all definitions in their Distribution Integrity Management Plan (DIMP) or other plans. 3. Operator definitions are not consistent with Part 192.
Examples of Evidence	1. Copy of written Distribution Integrity Management Plan (DIMP) or applicable portions that depict an omission or deficiency in the plan. 2. Operator records.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1003
Section Title	What do the regulations in this subpart cover?
Existing Code Language	*General.* This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in Sec. §192.1005-192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in §192.1015 of this subpart.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	**Interpretation: PI-11-0016 Date: 09-12-2012 –** Response to Atmos Energy; September 12, 2012 and DIMP FAQ C.3.7 asserting PHMSA's position that farm taps have been historically considered service lines, a subset of distribution pipelines and are thus subject to all distribution line requirements. **Interpretation: PI-11-0008 Date: 04-19-2011** - Response to Northern Natural Gas Company; Apr 19, 2011 and DIMP FAQ C.3.7 explained that - operators of distribution, gathering, and transmission lines whose system includes "farm taps" meeting the definition of a distribution line must have a DIMP covering these facilities.
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Distribution Integrity Management FAQs • **C.2.1** Must peak shaving and LNG facilities connected to our distribution pipeline system be considered in our DIMP?
Guidance Information	1. The DIMP must address all gas distribution systems covered by this part including systems in which the operator transports natural gas, liquefied petroleum gas (LPG), landfill gas (LFG), liquefied natural gas (LNG), and propane-air mixtures. 2. All distribution pipeline and appurtenances are subject to DIMP including mains, valves, fittings, regulator stations, drips, service lines, risers, service meter and regulator sets, farm taps, high pressure distribution systems and low pressure distribution systems. 3. Operators must follow their procedures. The DIMP and any individual procedures documents must include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 4. Master Meter and Small LPG operators are treated differently in the DIMP

	Rule than larger operators. For Master Meter and Small LPG operators, the integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis.
Examples of a Probable Violation	1. The operator's DIMP does not include all of the operator's distribution pipeline facilities. 2. The operator does not address LPG or other types of gas transported when applicable. 3. Necessary regulated pipeline systems are not covered by a DIMP. 4. The DIMP does not include all pipe and appurtenances.
Examples of Evidence	1. Copy of written DIMP or applicable portion that shows omission or deficiency in the DIMP. 2. Copies of the applicable pages of the DIMP showing that the operator has not clearly stated other types of gas are transported. 3. Operator records. 4. Documented photographic evidence demonstrating the violation. 5. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1005
Section Title	What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?
Existing Code Language	No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in §192.1007.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 4: Implementation time. Page 63909 • Comment Topic 11: Required documentation. Page 63915 Distribution Integrity Management FAQs • **C.3.1** If an operator has both natural gas and LPG systems, must it have two separate DIMP plans or may it have a single plan? • **C.3.2** Must an operator have one DIMP plan covering all of its systems or could it have separate plans for different systems or service areas? • **C.3.3** Will companies operating in several states need to develop individual DIMP plans for each state? • **C.3.4** What is the relationship between an operations & maintenance manual and a DIMP plan? • **C.3.6** How does the new DIMP rule impact operators of gas piping systems on military bases, Federal Government, or Indian Tribal Government land? • **C.3.7** Are operators required to include “farm taps” in their distribution integrity management plan? • **C.3.8** What do operators need to have implemented by August 2, 2011? • **C.3.10** What are the requirements for distribution systems put in service after 8/2/2011? • **C.3.11** What are the requirements for distribution systems acquired after 8/2/2011?

	Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 1 - Introduction 1.1-1.3 • Section 2 - Elements of a Distribution Integrity Management Plan 2.1-2.2 • Section 10 - Sample DIMP Approaches 10.1-10.2 Gas Distribution Integrity Management Program: Resources • DIMP Inspection Forms • Technical Reports • Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators • Plastic Piping Data Collection Initiative • Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 Distribution Management Integrity Program • SHRIMP - Simple Handy Rule based Integrity Management Plan • Industry Associations • Excavation Damage Prevention Organizations
Guidance Information	1. From 192.1001: *Integrity Management Plan* or *IM Plan* "means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart." An operator must have a written distribution integrity management plan (DIMP) that contains or references procedures for developing and implementing each required element in §192.1007. 2. The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. 3. The procedure must be documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the procedure. The procedures need to provide a description of who, what, when, where, and how the operator will perform the elements. The DIMP can be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis. Operators must follow their procedures. 4. The DIMP and any individual procedures' documents should include management approvals, origin date, and the effective date of the last revision. 5. From §192.1007, *Integrity Management Program or IM Program* "means an overall approach by an operator to ensure the integrity of its gas distribution system." The operator's integrity management program must include the appropriate set of procedures to develop and implement each program element as required in 192.1007. 6. An operator's DIMP may vary in length and complexity depending on the specific equipment in service, the variety of facilities, the locations, and referenced versus incorporated material. 7. The structure of the DIMP is not prescribed and may consist of a single comprehensive DIMP or multiple cross-reference volumes with referenced documents. The DIMP can be made available to personnel as hard-copy or computer based documents but must be accessible at locations where DIMP required activities are conducted. If the DIMP is computer based, the operator must provide a means to access the procedures in the event of computer failure.

	8. Purchased or off-the-shelf plans and procedures must be fully customized to the operator to cover their specific operating requirements, and the procedures must have adequate detail to clearly describe the manner in which each requirement will be met. *Guidance specific to an operator who transfers pipeline assets to another operator but retains responsibility, by contract, for maintenance and distribution integrity management activities.* 1. Which operator is accountable for implementing the DIMP? OPS and the States inspect operators for compliance with the pipeline safety regulations. An 'operator' is defined in 49 C.F.R. §192.3 as "a person who engages in the transportation of gas". A 'person' is further defined as an individual or firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof. If an operator retains responsibility for operations and maintenance responsibilities including DIMP activities, that operator is responsible for complying with the pipeline safety regulations.
Examples of a Probable Violation	1. The operator does not have a DIMP written and implemented by August 2, 2011. 2. The DIMP does not contain the necessary procedures to demonstrate that the DIMP was written and is being implemented. 3. A new system was put into operation and service without a written DIMP. 4. An operator who acquired an existing system and did not continue operations under the existing DIMP or did not incorporate the acquired assets into its DIMP.
Examples of Evidence	1. Copies of the applicable pages of the DIMP showing that the operator has not clearly stated that the DIMP was written and implemented by August 2, 2011. 2. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(a)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: (a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information. (1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline. (2) Consider the information gained from past design, operations, and maintenance. (3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities). (4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed. (5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, 76 FR 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-12-06 - Issued May 7, 2012** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517 and maximum operating pressure (MOP) required by 49 CFR 195.310. **Advisory Bulletin ADB-12-05 – Issued March 23, 2012** PHMSA urges owners and operators to conduct a comprehensive review of their cast iron distribution pipeline systems and replacement programs and to accelerate pipeline repair, rehabilitation, and replacement of aging and high-risk pipe. In addition ADB notes regulation requirement for natural gas distribution companies to develop DIMP for pipelines owned, operated or maintained.

	<u>Advisory Bulletin ADB-11-01 – Issued January 10, 2011</u> PHMSA-2010-0381; Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation. **<u>Advisory Bulletin ADB-09-02 Issued September 30, 2009</u>** Potential for issues with Weldable Compression Coupling Installation.
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 20: Knowledge of pipeline. a. Environmental factors, Page 63919 <u>Distribution Integrity Management FAQs</u> • **C.4.2** Can the DIMP plan incorporate by reference the operator's procedures from their other manuals or plans? • **C.4.a.1** The rule requires that an operator know its system. Must an operator excavate simply to gather information about parts of its system where it may not now have complete knowledge? • **C.4.a.2** There are some characteristics about an operator's system that may not be known during the development of the IM plan. What are PHMSA's expectations for filling those voids? • **C.4.a.3** Who qualifies as a "subject matter expert"? • **C.4.a.4** What data will be required to be collected for new gas pipelines going in the ground? • **C.4.a.5** What comprises "reasonably available" information? • **C.4.a.6** Must an operator's plan include the sources used to demonstrate an understanding of its gas distribution system? <u>Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8</u> • Section 3 Knowledge GPTC provides a useful list of records from which information is gathered. In addition to the information from the GPTC DIMP Appendix, the GPTC Guide Material Appendix G-192-17 contains a list of explicit requirements for reports, inspections, tests, written procedures, records and similar actions.

Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(a). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedures documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 2. An operator must have knowledge of its natural gas distribution system including, but not limited to, the following characteristics: location, material composition, piping sizes, joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, history, operating experience performance data, condition of system, and any other characteristics noted by the operator as important to understanding its system. This information may be obtained from sources including system maps, construction records, work management system(s), geographic information system(s), corrosion records, and personnel who have knowledge of the system (Subject Matter Experts) 3. The operator must have a list of the information sources used to develop the DIMP. 4. The operator knowledge of the system should be focused on those characteristics which are needed to assess threats, evaluate risks to the system to identify risk reduction measures, and group facilities with like characteristics. An operator must begin by reviewing the data that characterizes its unique distribution system as the initial step in identifying threats and assessing and prioritizing the threats. Characteristics evaluated by the operator must allow the operator to identify facilities with known and potential problems. For example, operators should examine the design characteristic "joining method" to determine if their system contains mechanically joined pipe that could be a threat to the integrity of the system. 5. Operators who transport gases other than natural gas need to describe in their DIMP how the characteristics of the gas impact the threats and risk and include the differences from natural gas. 6. The term "environmental factors" has caused some confusion. As clarified in the DIMP Final Rule in response to Comment #20, environmental factors are "necessary to assess the applicable threats and risk to gas distribution pipelines and does not refer to consequences." 74 Fed. Reg. 63906, 63919. The term "environmental" as used in the rule does NOT refer to "EPA" type environmental factors such as mercury regulators, PCBs, or contaminated soils (which require remediation when removed). It does refer to operating environment characteristics including but not limited to population density, landslide, corrosive soil, valve placement, seismic zones, flood zones, areas with wall-to-wall paving, frost impacts, geologic conditions, construction activities (significance of near-by construction), wash outs, types of soils, etc. Some of these factors will not apply to certain operators. An operator's DIMP must include information about the environmental factors reviewed but does not need to describe the criteria they used to select them to develop the knowledge of their system.

	7. The operator is required to have a list of the information sources used to develop the DIMP to demonstrate that they have considered all *reasonably available* records. All reasonably available records which provide information on a significant impact on system integrity must be included. 8. Some historical data may be no longer applicable to the current condition of the pipeline system. If the pipe was replaced, the data about the previous pipe may no longer be relevant. Such data may be relevant where the circumstances (e.g., construction practices, coatings, backfill materials, pipe materials, environmental conditions) of the pipe prior to replacement exist elsewhere and are relevant to existing risks in the operator's system. For example, if bare steel pipe has been replaced, but some bare steel still exists in the system, then data concerning the replaced pipe may still be relevant. 9. If an operator acquires a pipeline and the historical records were not obtained or are not reasonably available, the records do not need to be recreated. However, this missing data must be identified as such within the operator's DIMP, and a plan must be established for collection of relevant information. 10. Operators need to consider failures without a release to identify potential threats, and this type of information is considered reasonably available. For example, operators may evaluate where pressure regulators froze off and where upsets in the system could have occurred. 11. For data identified by the operator as needed for a threat identification and risk evaluation, there needs to be a process to identify facilities for which records are missing, inaccurate, or incomplete. 12. Collecting additional data and improving existing data is only required to occur as part of normal pipeline activities and over time. There must be a mechanism for individuals performing normal pipeline activities to know what additional data is needed. 13. Forms, recordkeeping procedures, data management systems and/or other methods used to collect information related to the physical attributes and/or operating and maintenance activities of distribution pipeline facilities should be appropriately modified to provide for the collection of reasonable available information. Personnel should be trained to properly collect and record the needed information and use the required forms.
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks required. 2. The operator fails to follow the written procedures. 3. Operator did not demonstrate that they have looked at all reasonably available sources to find information from past design, operations, inspections, or maintenance activities. 4. Operator did not specifically list which documents were used to assemble knowledge of its system. 5. Operator does not gather or use reasonably available data on the entire pipeline that could be relevant to performing their threat assessment, risk evaluation or as needed to group like facilities. 6. DIMP did not identify the records containing the appropriate characteristics of the pipeline's operating conditions to assess each threat category and subcategory to the operator's pipeline. 7. DIMP did not identify the records containing the appropriate environmental characteristics to assess each threat category and subcategory to the operator's pipeline.

	8. There is no procedure for identifying needed missing, inaccurate or incomplete data. 9. The operator has not identified missing, inaccurate or incomplete data. 10. The operator has identified missing, inaccurate or incomplete data but does not have a procedure or plan to collect the missing data and information over time. 11. Operator failed to retain data on new pipeline installed.
Examples of Evidence	1. Copies of the applicable pages of the DIMP showing that the operator has not clearly stated the documents used to develop knowledge of the system. 2. The list of documents used to develop knowledge of the system is inadequate in identifying design, operating, or environmental characteristics of the pipeline system. 3. Copies of applicable pages of the DIMP showing that the DIMP is not detailed enough for an inspector to make a reasonable determination as to the accuracy and thoroughness of the process. 4. Documented photographic evidence demonstrating the violation. 5. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(b)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: * * * * * (b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: Corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, 76 FR 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**<u>Advisory Bulletin ADB-13-04 – Issued August 22, 2013</u>** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. **<u>Advisory Bulletin ADB-13-03: Correction – Issued October 31, 2013</u>** PHMSA is issuing an Advisory Bulletin to remind owners and operators of liquefied petroleum gas (LPG) and utility liquefied petroleum gas (utility LP-Gas) plants that although they must follow the American National Standards Institute/National Fire Protection Association (ANSI/NFPA) standards 58 or 59, they must also follow certain sections and requirements of Part 192. **<u>Advisory Bulletin ADB-13-02 – Issued July 12, 2013</u>** PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in case of flooding.

Advisory Bulletin ADB-12-05 – Issued March 23, 2012
PHMSA urges owners and operators to conduct a comprehensive review of their cast iron distribution pipeline systems and replacement programs and to accelerate pipeline repair, rehabilitation, and replacement of aging and high-risk pipe. In addition ADB notes regulation requirement for natural gas distribution companies to develop DIMP for pipelines owned, operated or maintained.

Advisory Bulletin ADB-12-03 – Issued March 6, 2012
PHMSA advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation.

Advisory Bulletin ADB-11-05 – Issued August 26, 2011
PHMSA advisory to remind owners and operators of gas and hazardous liquid pipelines of potential for damage to pipeline facilities caused by the passage of Hurricanes.

Advisory Bulletin ADB-11-04 – Issued March 20, 2012
Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding.

Advisory Bulletin ADB-11-02 – Issued February 9, 2011
Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems.

Advisory Bulletin ADB-10-03 – Issued March 24, 2010 Pipeline Safety: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe.

Advisory Bulletin ADB-09-02 – Issued September 30, 2009
Potential for issues with Weldable Compression Coupling Installation

Advisory Bulletin ADB-08-02 – Issued March 4, 2008
Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems

Advisory Bulletin ADB-07-01 – Issued September 6, 2007
Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe

Advisory Bulletin ADB-06-03 – Issued November 22, 2006
Notice to Operators of Natural Gas and Hazardous Liquid Pipelines to Accurately Locate and Mark Underground Pipelines Before Construction-Related Excavation Activities Commence

Advisory Bulletin ADB-05-05 – Issued August 10, 2005
Inspecting and Testing Pilot-Operated Pressure Relief Valves

Advisory Bulletin ADB-04-01 – Issued September 29, 2004
Hazards Associated with de-watering of pipelines

	<u>Advisory Bulletin ADB-02-01 – Issued May 24, 2002</u> Notice to Operators of Natural Gas and Hazardous Liquid Pipelines To Encourage Continued Implementation of Safe Excavation Practices **<u>Advisory Bulletin ADB-97-05 – Issued November 12, 1997</u>** Potential Failure of Check Valves Following Remanufacturing **<u>Advisory Bulletin ADB-97-03 – Issued March 4, 1997</u>** Potential Soil Subsidence on Pipeline Facilities **<u>Advisory Bulletin ADB-95-02 – Issued August 9, 1995</u>** Increased Pipeline Transportation Security Measures **<u>Advisory Bulletin ADB-94-05 – Issued November 2, 1994</u>** Pipelines Affected by Flooding **<u>Alert Notice ALN-92-01 – Issued January 8, 1992</u>** Lightning-induced electrical discharge from tracer wire to plastic pipe. **<u>Alert Notice ALN-89-01 – Issued March 8, 1989</u>** Update: Additional findings relative to factors contributing to operational failures of pipelines constructed by ERW prior to 1970 **<u>Alert Notice ALN-87-01 – Issued March 13, 1987</u>** Incident involving the fillet welding of a full encirclement repair sleeve on a 14" API 5LX-52 pipeline; King of Prussia, PA 10/07/86 pipeline failure **<u>Alert Notice ALN-86-02 – Issued February 26, 1986</u>** Plastic Piping, Mechanical Coupling
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 21: Threat identification, b. Sources of information. Page 63920 <u>Distribution Integrity Management FAQs</u> • **C.4.b.1** Must an operator use a computer-based risk analysis model? • **C.4.b.2** Must each of the 8 threats be considered for every pipeline type? • **C.4.b.3** The DIMP requirements include knowing the condition of facilities that are at risk for potential damage from external sources. Cross bores of gas lines in sewers have been reported at 2-3 per mile in high risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in the proximity of each other. Does the potential for cross bore of sewers resulting in gas lines intersecting with sewers need to be determined? • **C.4.b.4** Are pipeline “overbuilds” a threat? Should the “other concerns” threat category contain pipeline overbuilds (building put over a pipeline)?

	• **C.4.b.5** We used leak causes which we have experienced in the past to identify threats. For example, washouts in our system have not caused leaks in the past so washouts were not identified as a threat. Should washouts be classified as a potential threat due to the possibility of coating damage? • **C.4.b.6** Since we have not experienced any issues with pre 1973 Aldyl "A" pipe in the past, we did not subdivide plastic pipe in our risk evaluation. It is a potential threat to us only because of other operators' experience. Should we have treated it as an applicable threat? • **C.4.b.7** Must I consider historical leak data after a section of pipeline has been replaced? • **C.4.b.8** We often replace a section of pipeline rather than repairing individually the leaks in that section. In this case, must we record the number and grade of leaks? • **C.4.b.9** We are experiencing problems in ranking potential threats since some of the low frequency events have not occurred on our systems, to date. We are concerned about mixing apples and oranges by assigning a frequency or probability to a threat that has not occurred and ranking it along with events that do have frequency. How should we account for low or no frequency threats in evaluating and ranking risks? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 4 - Identify Threats • Table 4.1 Sample Threat Identification Method • Section 5.1 Evaluate and Rank Risk – General
Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(b). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedures documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 2. The threat identification process must meet the need of establishing a realistic identification of the threats and provide a determination of whether their frequency and level of significance require an action that goes beyond normal operating practices. An understanding of threats and risks specific to an operator's system comes from analyzing the information in company's operations, maintenance, and inspection records, including, but not limited to, the following: specific surveys, patrolling records, corrosion control records, and leak and incident data. 3. Even if an operator concludes that a particular threat is not applicable to sections of its pipeline, the basis for drawing such conclusions must be documented. Operators may not discount or eliminate any existing or potential threat for a

	subsystem without an adequate basis for doing so. This basis must consider pipeline failure history, design, manufacturing, construction, operation, and maintenance. Prior to exclusion of a potential threat, operators should perform analysis of the "Other" leak cause data to ensure the potential threat has not been experienced to date. 4. Unavailability of information is not justification for exclusion of a threat. Where data are missing or insufficient, conservative assumptions may be used in the risk assessment. Records must be maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of risk analysis results can be considered. 5. In order to consider the 8 primary threats, the operator must review the data on the records which contain information they could use to determine the extent of the problem caused by each threat. Perceptions of problems or lack of problems need to be supported by available information. 6. Excavation damage must be included in the threats considered in the DIMP, even if the operator has good external damage control experience and a thorough damage prevention program. It is not acceptable for an operator to say that this threat is dealt with outside of DIMP and therefore need not be included. Excavation damage is always a potential threat, regardless of whether a specific system/subsystem has experienced damage 7. Potential threats are threats where the operator has not necessarily experienced a leak (i.e., release of gas) but they have conditions conducive to the threat (e.g. atmospheric corrosion, hurricanes, flooding, excavation damage, materials with known integrity issues). Examples include, but are not limited to, the following: a. Trenchless technology used in the area – unknowingly bored thru sewer or water lines b. Future utility/road improvement projects c. Discovery of a material not previously known to be in the system d. Customers built structures over existing pipelines e. Overpressurization events f. Instances of pipe damage (including damage to tracer wire) that did not result in a release g. Pipe materials susceptible to brittle failure modes 8. Possible sources of information to consider when identifying potential threats include past O&M procedures, purchase orders, material lists from old field orders or standards, and information from industry sources (e.g., plastic pipe data committee or PHMSA Advisory Bulletins. Information should include past continuing surveillance records (192.613). 9. Many operators performed measures to reduce risk prior to the DIMP rule. If the measures were effective, the operator may have not experienced any failures due to the threat the measure addressed. The operator has prevented or mitigated a potential threat, and these activities need to be included in the threat identification and risk evaluation.

Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks required. 2. The operator fails to follow the written procedures. 3. The procedures do not include a review of all of the 8 primary threats. 4. All of the 8 primary threats required by the rule were not adequately considered and/or evaluated. 5. Multiple threats from within the 8 primary threat categories were not adequately evaluated to characterize the operator's system. 6. Specific threats were eliminated from consideration without adequate justification. 7. Operator does not use relevant operating and maintenance records in evaluating each threat. 8. Elimination of a threat is not sufficiently documented. 9. Procedures did not adequately describe the requirements for identifying and evaluating threats. 10. Procedures do not contain sufficient detail and clarity to allow anyone using them to understand and follow them. 11. Operator did not use reasonable or appropriate subdivision of threats to identify existing and/or potential threats. 12. Identification of threats relies on information from Subject Matter Experts who lack appropriate knowledge and experience. 13. The procedures do not include a review of the potential threats. 14. Operator did not use all reasonably available records to identify threats. 15. Operator's DIMP did not consider data from external sources to identify potential threats. 16. DIMP did not identify the records containing the appropriate characteristics of the pipeline's design to assess each threat category and subcategory to the operator's pipeline. 17. The operator's definition of 'excavation damage,' in its written DIMP or in how the DIMP is implemented, does not include non-leak damages including damage to coatings, supports, cathodic protection or housings.
Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate procedures. 2. Reasonably available external information (e.g., Advisory Bulletin) identifying a threat applicable to the operator's system that was not considered in developing the DIMP. 3. Documented photographic evidence demonstrating the violation. 4. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(c)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: * * * * * (c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, 76 FR 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-12-05 – Issued March 23, 2012** PHMSA urges owners and operators to conduct a comprehensive review of their cast iron distribution pipeline systems and replacement programs and to accelerate pipeline repair, rehabilitation, and replacement of aging and high-risk pipe. Also, notes regulation requirements for natural gas distribution companies under DIMP.
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 22: Risk assessments. Page 63920 Distribution Integrity Management FAQs • **C.4.c.1** What are the key things an operator should be focusing on when developing an effective risk assessment methodology? • **C.4.c.2** From which date are operators required to collect data for their plan? • **C.4.c.3** How are newly identified threats to the system's integrity expected to be handled in an operator's DIMP plan? • **C.4.c.5** Do multiple threats need to be considered for each facility grouping? Do all threats need to be in one relative risk ranking? • **C.4.c.6** What is expected of multi-state operator in regards to a risk ranking?

	• **C.4.c.7** We plan to perform a risk ranking by state. Regardless of the outcome of the risk ranking, we will not decrease the historical level of expenditures in each state. However, a system wide risk ranking will be used to determine where expenditures beyond historical levels will be allocated. Does that meet the intent of the state by state risk ranking? • **C.4.b.9** We are experiencing problems in ranking potential threats since some of the low frequency events have not occurred on our systems, to date. We are concerned about mixing apples and oranges by assigning a frequency or probability to a threat that has not occurred and ranking it along with events that do have frequency. How should we account for low or no frequency threats in evaluating and ranking risks? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 5 – Evaluate and Rank Risk
Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(c). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedures documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 2. Once threats have been identified, the operator must develop a method to assess and prioritize the associated risks in order to address those of greatest concern first. 3. In performing a risk analysis, it is important to note that risk is the likelihood of an event occurring times the consequence of that event. An event that is highly likely and also has a high public safety consequence constitutes an event of greatest concern. An unlikely event having minimal consequence may not justify extraordinary precautions. An unlikely event that could have very high consequences may justify additional precautions as distribution incidents are often events that are of low likelihood but of high consequence. 4. Based on the analysis, the operator may consider additional segmentation of its distribution system in order to focus on certain portions of the system for risk evaluation and risk management actions. Segments exhibiting similar attributes and operational and maintenance history should be grouped together for application of measures to reduce risk. If the subsystems are too large and average numbers are used for the system as a whole, higher risk pipe may not be adequately identified. 5. The operator should have developed weighting factors for each threat specific to their system(s) dependent upon their unique operating environment. 6. The final risk score must take into account both likelihood and consequence factors. The operator must identify both the likelihood

	(frequency) and the consequences (potential impact) of failures due to each threat/subcategory of threat for each system to determine the relatively risk. When risk reaches a threshold set by the operator measures to reduce risk may be needed to address the threat. *a. Examples of Likelihood factors:* i. Leaks per mile of main by material type ii. Leaks per unit of services (based on size of operator) iii. Amount of construction activity in area iv. Number of hits per unit locate tickets *b. Examples of Consequence factors:* i. Operating pressure ii. Population density ("downtown" versus rural) iii. Impact of loss of supply iv. Number of customers affected v. Proximity to structures and critical facilities (e.g. schools and hospitals) vi. Proximity to known groups of people with limited mobility (usually institutionalized) 7. Characterizing a distribution system into logical units facilitates the process of prioritizing risks. If subdivision is warranted, the distribution system should be divided into a sufficient number of distribution segments in order to effectively assess the threats to the system. An operator can manage risks by addressing significant threats to the specific sections. To the extent that a threat is significant, it may be prevalent throughout the operator's system or it may exist only in certain specific (localized) sections of the system. 8. It is inadequate for an operator to conclude that a pipeline is not subject to any particular threat or threats, based solely on the fact that it has not experienced a pipeline failure that has been attributed to the threat(s). An operator also must consider potential threats. 9. The operator must have a process for validating the results of the risk ranking, and the operator must follow the procedure. The results generated by the model should agree with the consensus of the validation group. If the analysis results do not identify known risk factors, the evaluation model/method should be questioned, analyzed, and if necessary, revised. The verification process should compare the results of the risk evaluation to operator and industry experience (e.g., Advisory Bulletins, PPDC reports, vendor notifications). Methods of validation may include: *a.* Team review of results *b.* Subject Matter Expert reviews
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks required. 2. The operator fails to follow the written procedures. 3. Operator has not conducted a risk assessment 4. A comprehensive risk analysis process was not adequately developed. 5. All portions of pipelines were not included in the risk analysis 6. The process did not adequately consider risk factors unique to the operator's systems when using a "standard" risk model 7. The risk analysis process was not adequately documented

	8. The risk analysis process did not adequately consider all required risk factors 9. Risk weighting factors were not adequately validated or justified 10. Likelihood or consequence of pipeline failures was not adequately considered in the risk analysis 11. Explicit guidelines and process formality were not provided to support use of Subject Matter Experts in risk analysis 12. Operator-specific leak/failure history and other operating experience were not adequately considered in the in risk analysis 13. Field input was not adequately incorporated in the risk analysis 14. General or default values were inappropriately used where data has not been collected 15. Poor quality data was used in the risk analysis 16. The basis for risk model scores was not adequately documented 17. The DIMP does not contain procedures for determining the applicable potential threats, the likelihood of the failure, and the potential consequence of the failure. 18. Operator subdivided its system into regions that do not have similar characteristics and for which similar actions are likely to be effective in reducing risk. 19. Subdivision combines systems with differing characteristics and for which similar actions are not likely to be effective in reducing risk. 20. Subdivision by operating system based solely on geographic location and not on system characteristics. 21. Risk analysis results did not adequately identify dominant risk factors 22. Risk analysis results were not adequately aggregated such that segment-specific risk measures were obscured 23. The impact of uncertainties on the results were not adequately considered 24. Risk assessment does not prioritize pipeline segments 25. The process the operator describes in the procedure is not sufficiently documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the process. 26. Procedures do not contain adequate detail and clarity to allow for a clear understanding of the process. 27. Risk calculation does not consider the likelihood and consequences of current and potential threats. 28. Risk calculation does not determine the relative importance of threats. 29. Operator did not validate the results of the risk evaluation. 30. The selection process of the Subject Matter Experts was flawed. 31. Operator history is not consistent with the output of the risk evaluation model. 32. Information provided by validation team members do not concur with results, and these differences were not evaluated and addressed. 33. The operator has no documentation validating the ranking results.

Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate procedures. 2. Printout of operators risk ranking results. 3. Portions of the documentation of a commercial product that demonstrate it should not have been used in the manner the operator used it. 4. Documented photographic evidence demonstrating the violation. 5. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(d)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: * * * * * (d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, FR 76 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**<u>Advisory Bulletin ADB-13-01 – Issued January 30, 2013</u>** PHMSA advisory to notify the owners and operators of gas and hazardous liquids pipelines systems and LNG facilities, that, as required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, the agency will issue a proposed rule to revise telephonic reporting regulations to establish specific time limits for telephonic or electronic notice of accidents and incidents involving pipeline facilities to the National Response Center (NRC). PHMSA will issue a proposed rule at a later date, but encourages owners and operators of the gas and hazardous liquids pipeline systems and LNG facilities, as a practice, to report such accidents and incidents within one hour of confirmed discovery. **<u>Advisory Bulletin ADB-12-09 – Issued October 11, 2012</u>** PHMSA advisory to remind operators of gas, hazardous liquid, and liquefied natural gas pipeline facilities that operators should immediately and directly notify the Public Safety Access Point (PSAP) that serves the communities and jurisdictions in which those pipelines are located when there are indications of a pipeline facility emergency. **<u>Advisory Bulletin ADB-10-08 – Issued November 3, 2010</u>** Pipeline Safety: Emergency Preparedness Communications. **<u>Advisory Bulletin ADB-01-02 – Issued October 4, 2000</u>** Emergency Plans and Procedures for Responding to Multiple Gas Leaks and Migration of Gas into Buildings. **<u>Advisory Bulletin ADB-99-04 – Issued August 23, 1999</u>** Directional Drilling and Other Operations Conducted in Proximity to Underground Pipeline Facilities.

	<u>Advisory Bulletin ADB-94-03 – Issued February 23, 1994</u> Pipelines in a common right-of-way, parallel right-of-way, or cross a rail right-of-way. **<u>Advisory Bulletin ADB-94-02 – Issued January 19, 1994</u>** Valve Location and Spacing. **<u>Advisory Bulletin ADB-93-03 - July 29, 1993</u>** Advisory to Owners and Operators of Hazardous Liquid and Natural Gas Pipeline Facilities in Areas of Flooding. **<u>Alert Notice ALN 91-04 - Issued November 20, 1991</u>** NTSB recommendations S P-91-3/P-91-4, 03/15/90 NY leak/explosion: Requiring operators to extend their public education/emergency preparedness programs. **<u>Alert Notice ALN 89-02 - Issued April 13, 1989</u>** Results of OPS-conducted investigation of the San Bernardino, CA, 05/12/89 train derailment; each gas/liquid operator should test check valves.
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 14: Leak monitoring. Page 63917 • Comment Topic 16: IM program evaluation and improvement. Page 63918 • Comment Topic 23: Performance measures. Page 63922 Distribution Integrity Management FAQs • **C.4.d.1** Must an operator implement additional or accelerated actions to reduce risk from its pipeline? • **C.4.d.2** How will small operators, with limited staff, be able to implement the requirements for risk analysis and selection of risk control measures? • **C.4.d.3** If an operator already has a leak management program, does the operator have to implement a new program in response to this regulation? • **C.4.d.4** Why not simply require operators of gas distribution pipelines to replace old pipe? • **C.4.d.5** What kind of issues should an operator focus on in addressing the threat of Excavation Damage as part of its DIMP Plan? • **C.4.d.6** In order to eliminate the need for a leak management program, how quickly would an operator need to repair all leaks? • **C.4.d.7** Can the installation of excess flow valves be a method to mitigate risks? • **C.4.d.8** What criteria should an operator use to identify when a measure to reduce risk is needed? • **C.4.d.9** Do all actions operators take to reduce risk need to be included in their DIMP plan? • **C.4.d.10** We have heard that operators will be required to implement specific measures to reduce risk. Can you describe the required actions? • **C.4.d.11** How can an operator demonstrate that their leak management program is effective?

	Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 6 – Identify and Implement Measures to Address Risks
Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(d). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedures documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 2. The design and operation of distributions systems is so diverse that no single risk control method is appropriate in all cases. The operator must have a documented list of measures to reduce risk they are planning on implementing. Risk can be reduced by implementing risk control practices that decrease the likelihood of the event occurring, or mitigate the consequence of the event. 3. In considering gas distribution systems, it is essential to remember that the consequences of a failure in a distribution system may take a protracted period of time to develop (e.g., gas migration). During this period of time, certain techniques can be used to detect the failure and actions can be taken to address the failure before it results in an incident. 4. The process for identifying additional measures must be based on identified threats to each pipeline segment and the risk analysis. Clearly, facilities and groups of facilities that represent the highest risk are the most important candidates for measures to reduce risk. Therefore, the operator must ensure that the measures selected to reduce risk that are to be implemented with the highest priority are for the highest ranked segments/facilities as indicated by the risk analysis. 5. Operators were required to implement and schedule measures to address the prominent risks identified in their risk evaluation by August 2, 2011. This process is an ongoing one, and revisions are appropriate and expected. Some measures can be implemented immediately. Others (e.g., pipe replacement) may require budget approval and allocation of resources; operators should have considered this and scheduled major measures appropriately in their DIMP. Operators must provide a schedule of when measures to reduce risk will be taken, and to act as quickly as practical after identifying the need for such risk controls. In situations where lengthy periods are required for implementation, operators should determine if there are relatively simple, interim measures that can be taken to reduce risk while major projects are being implemented. Operators are expected to promptly identify the need for measures in the event a new risk is identified. 6. The operator must be able to produce records demonstrating that a risk measure has been implemented or is scheduled to be implemented. Scheduled measures should be justified based on complexity of the implementation (considerations: procurement, need for additional resources, coordination with local jurisdictions, training of qualified personnel, etc.). The procedure must detail the basis for

	decisions and be documented as part of the operator’s DIMP. Decisions include: a. Which measures to reduce risk to implement b. Schedule for implementation of the measure(s) to reduce risk c. Performance metrics for the measures to reduce risk 7. The risk drivers for each high risk segment should be considered in determining the most effective mitigation option. The operator should understand the risk analysis results sufficiently to determine which factors affect risk the most (i.e., the "risk drivers") and select preventive and mitigative measures that affect the dominant risk factors. The use of gross or overall risk scores for determining measures to reduce risk, while important, may not contain enough information to identify the most effective candidate measures for reducing risk. While the evaluation may or may not result in any actions being implemented, it is important that the operator’s process gives priority to the highest risk portions of the pipeline. 8. Leak data must be evaluated to identify trends in leaks for pipe of different attributes. A leak management program is effective if hazardous leaks are repaired promptly and all other leaks are graded, scheduled for repair or monitored. The leak management system must provide for a recheck of leak repairs after it is repaired before the leak is cleared. 9. “Repaired when found” means that all leaks are treated as hazardous leaks, and either repaired promptly or continuously monitored by operator personnel until repaired. Repair within a delayed period after discovery (e.g., 1 month) is not “repaired when found.” Operators who do not repair all leaks promptly or continuously monitor the leaks until repaired must have a leak management program. 10. An effective leak program includes an audit/field verification to ensure that individuals assigned to evaluate leaks are classifying or grading leaks consistently across the system. The procedures should include requirements for periodic field evaluation of active leaks to ensure that the leak has not become more severe requiring a classification or grading change. Routine self-assessment of the overall leak management plan should be performed by the operator. The operator should take actions if inconsistencies are identified.
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks required. 2. The operator fails to follow the written procedures. 3. A comprehensive risk analysis process was not adequately implemented. 4. The procedure does not require identification of measures to reduce risk. 5. The risk mitigative measures identified by the operator do not specifically address identified risk factors. 6. The procedure does not require a schedule for implementation of measures to reduce risk. 7. The procedure for identifying additional measures is not based on identified threats to each pipeline segment and the risk analysis. 8. The procedure for evaluating additional preventive and mitigative measures does not adequately describe the method used to assure the appropriate selection of the risk mitigative measures intended to reduce risk for a specific threat. 9. Procedures do not contain adequate detail or clarity to allow individuals that were not previously involved in the process to perform the task.

	10. The process did not adequately require a documented justification for decisions regarding additional preventive and mitigative measures. 11. The DIMP does not provide a process to implement the mitigative measures. 12. A schedule for implementation of mitigative measures is not provided. 13. Measures to reduce risk have not been performed according to operator's procedure. 14. Operator has not identified measures to reduce risk when required by their risk evaluation. 15. Operator has not kept records demonstrating implementation of measures to reduce risk. 16. The operator cannot produce documentation of measures already in progress. 17. All required risk factors were not adequately considered in the preventive and mitigative evaluation process. 18. The impact of preventive or mitigative actions on risk was not adequately evaluated. 19. Risk mitigative measures housed in other operator programs were either not included or referenced in the DIMP. 20. Leaks graded as non-hazardous are becoming hazardous leaks before repair, and the operator has not self-assessed and made appropriate adjustments to its leak management program. 21. The operator is not rechecking leaks within the scheduled time period. 22. The operator has not evaluated the leak program to determine if it is effective. 23. The operator has not assured consistency in leak grading across the system. 24. The procedure is not sufficiently documented to allow an inspector to make a reasonable determination as to the accuracy and thoroughness of the process. 25. Procedures do not contain sufficient detail and clarity to allow anyone using them to perform the task. 26. A leak management program was either not included or not referenced in the DIMP. (Not applicable if an operator repairs all leaks when found).
Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate procedures. 2. Copies of the risk evaluation demonstrate that measures to reduce risk were needed but not scheduled. 3. Record indicating that the operator is not making progress in implementing measures to reduce risk. 4. Record indicating the operator is not adequately following the leak management program (records indicating that monitoring deadlines are not being met, repairs are exceeding deadlines, etc.) 5. Documented photographic evidence demonstrating the violation 6. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(e)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: * * * * * (e) *Measure performance, monitor results, and evaluate effectiveness.* (1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following: (i) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause; (ii) Number of excavation damages; (iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center); (iv) Total number of leaks either eliminated or repaired, categorized by cause; (v) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and (vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, 76 FR 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-12-10 – Issued November 29, 2012** PHMSA is issuing this Advisory Bulletin concerning operator integrity management program evaluation using meaningful metrics.
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 23: Performance measures. Page 63921 Distribution Integrity Management FAQs • **C.4.e.1** Why has PHMSA selected the performance measures that it has for periodic reporting? • **C.4.e.2** Does every measure to address risk require a performance measure?

	[Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8] • Section 7 – Measure performance, monitor results and evaluate effectiveness
Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(e). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedure documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 2. An operator must have provisions for measuring integrity management program effectiveness. The operator's program documentation should identify that these measures are to be reviewed and the frequency at which they will be reviewed. 3. Operators must develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. Program documentation must include the process by which operators establish a baseline measurement for each performance measure from which to evaluate changes. Program documentation must specify that the measures are to be taken and identify the specific dates the measures should cover. 4. Threat-specific measures will only apply if the operator has determined that measures to reduce risk are needed. If it is a new performance measure, the operator may only have one data point and then will collect more data in the future from which to evaluate changes. Operators may not have historical data to establish a baseline for all performance measures. In these cases, the operator must have a plan for collecting the data going forward to establish that baseline. 5. The purpose of the excavation damage performance measure for reporting the number of excavation tickets is to normalize excavation damage information in order, for example, to help determine whether reduced excavation damages are a result of improved damage prevention programs or less construction (excavation) activity. This measure, by itself, is not informative of the effectiveness of an operators DIMP program, and an operator need not establish a baseline for this element. Normalization is necessary because changes in the amount of construction activity will affect the number of excavation damages but are outside the control of an operator's IM program. Analyses will likely normalize per 1000 tickets but this is a simple arithmetic adjustment if the basic data is available. 6. Each implemented risk reduction measure or group of measures to reduce risk must have a performance measure associated with it that is designed to monitor its effectiveness. Monitoring the effectiveness of measures to reduce risk allow an operator to make substantiated determinations as to the adequacy of the implemented measure to reduce risk and whether the measure to reduce risk should be continued, revised, or cancelled.

	7. Performance measures should reflect the purpose of the DIMP or specific risk control practice. Performance measures should be something that can be counted, graphed and validated. An operator need not adopt all possible performance measures. It would be acceptable for the operator to select "a critical few" measurements. There are often decreasing returns as measurements are added, and too many measurements can overwhelm the measurement system. 8. Operators should establish trigger points or thresholds to prompt them to review the effectiveness of their risk reduction measures. Operators may determine through the reviews that the risk reduction measure must be changed or that additional measures are needed.
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks required. 2. The operator fails to follow the written procedures. 3. Operator does not have threat-specific performance metrics when needed. 4. The process the operator describes in the procedure is not sufficiently documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the process. 5. Procedures do not contain sufficient detail and clarity to allow anyone using them to understand and follow them. 6. Operator lacks a plan to establish a baseline for performance measures where historical data for a baseline does not exist. 7. Operator does not include an explanation of how the effectiveness of measures to reduce risk will be measured. 8. Performance measures selected will not measure effectiveness of the measure implemented to reduce risk. 9. Performance measures indicate that a risk reduction measure is not effective, but the operator has not taken actions to revise/replace the measure. 10. Operator did not collect performance measure data. 11. Operator did not analyze the performance measure data to monitor the progress of the risk reduction measure. 12. Operator did not evaluate the data to determine if the measure to reduce risk was effective. 13. Performance measures used by the operator did not include number of excavation tickets, number of leaks, or number of hazardous leaks.
Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate procedures. 2. Copies of operator records of performance measures, or other associated documentation, which demonstrates that a risk reduction measure is not effective. 3. Copies of operator records of performance measures, or other associated documentation, which demonstrates that a risk reduction measure is not effective and corrective actions have not been taken. 4. Documentation demonstrating the Operator did not collect or evaluate performance measure data. 5. Documented photographic evidence demonstrating the violation. 6. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(f)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: * * * * * (f) *Periodic Evaluation and Improvement.* An operator must reevaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, 76 FR 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 16: IM program evaluation and improvement. Page 63917 Distribution Integrity Management FAQs • **C.4.f.1** How often does an operator need to evaluate its program? • **C.4.f.2** What constitutes a periodic evaluation? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 8 – Periodic Evaluation and Improvement
Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(f). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedures documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005.

	2. An operator must complete an evaluation of its distribution integrity management program periodically to monitor its effectiveness in assessing distribution integrity and addressing identified threats. Program evaluation is performed to confirm that the essential elements of the process are identified, implemented and effective. In addition, threats and their priorities may change over time as conditions change or as mitigation projects are completed. 3. The period for the evaluation of program effectiveness must be as frequent as needed to assure distribution system integrity, but cannot exceed five years (rule requirement). This evaluation period must be determined by the operator and included in its written integrity management program. The time frame for evaluation of individual internal performance measures may be different. The periodic review of the written integrity management program will include an evaluation of the appropriateness of these operator established intervals. 4. The evaluation of program effectiveness should include the following items to determine if modifications to the program need to be made: a. Risk prioritization results b. Risk control practices c. Failure analysis results d. Performance measures 5. The method of program evaluation could range from a formal audit of the program to a simple review of the above items by a subject matter expert, based on the needs and complexity of the program. 6. Corrective actions taken by an operator to improve the integrity management program must be documented and monitored for effectiveness. 7. The periodic evaluation must specifically relate to the threat assessment, risk evaluation, measures to reduce risk, and performance measures. These reviews must examine the effectiveness of the measure(s) to reduce risk and its specific performance measure(s) with recommendations for improvement where necessary. 8. Results of a periodic review must include the appropriate specificity to identify improvements, and generic statements about implementing improvements are not acceptable.
Examples of a Probable Violation	**Evaluation** 1. The operator does not have a procedure that covers the tasks required. 2. The operator failed to follow the written procedures. 3. Adequate procedures were not developed for conducting IM program effectiveness evaluations 4. The procedure did not identify the frequency of the periodic evaluation. 5. Operator did not conduct a program re-evaluation at least every five years. 6. The procedure did not adequately include reviews or audits of IM programs 7. An operator's DIMP evaluation process does not specifically address the means (methods) the operator implemented to track DIMP performance or the procedure does not have specific frequencies (time frames) at which the operator must track DIMP performance. 8. An operator's DIMP evaluation procedure does not assess whether the DIMP is effective in reducing risk. 9. An operator's DIMP evaluation process does not provide the operator information on implementing improvements in its DIMP effectiveness based on findings from the evaluation.

	10. The operator's evaluation process is not based on sound and repeatable principles or is not sufficiently documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the process. **Improvement** 1. An operator did not change its DIMP, as required to address information obtained through annual reviews, program evaluations, or whenever any change occurs that would materially alter any of the elements in the DIMP. 2. An operator did not actually make the changes to the DIMP or did not implement the changes to the DIMP when and where the program evaluation identified changes were required. 3. An operator did not thoroughly document the changes including the purpose, content, and date completed. 4. The process the operator describes in the procedure is not sufficiently documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the process. 5. Procedures do not contain sufficient detail and clarity to allow anyone using them to perform the task. **Implementation** 1. A DIMP program evaluation was not adequately performed and/or the results were not adequately documented 2. Adequate actions were not identified to improve the DIMP based on a review of the evaluation 3. Actions identified by the DIMP program evaluation were not adequately implemented 4. Response to performance measures indicating poor performance was inadequate
Examples of Evidence	1. Copies of the applicable DIMP pages supporting any of the violations discussed above either separately or in combination. 2. Copies of an operator's procedure showing it does not meet the specified requirements 3. Documentation demonstrating the Operator did not perform a DIMP Program Evaluation. 4. Documentation demonstrating the Operator did not react to the results of a DIMP Program Evaluation. 5. Documented photographic evidence demonstrating the violation. 6. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1007(g)
Section Title	What are the required elements of an integrity management plan?
Existing Code Language	A written integrity management plan must contain procedures for developing and implementing the following elements: * * * * * *(g) Report results.* Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by §191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	192-116, FR 76 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 26: Annual Report Form. Page 63923 Distribution Integrity Management FAQs • **C.4.g.1** When must operators start collecting and maintaining records with data needed for performance measures? • **C.4.g.2** When are performance measures due on Annual Reports? • **C.4.g.3** Can PHMSA further define the number of excavation tickets on the new form? • **C.4.g.4** For municipal operators or joint utility operators, should the number of excavation tickets include all excavation tickets or just those sent to the gas department? • **C.4.g.5** Are multiple tickets for a single job counted as a single excavation ticket? • **C.4.g.6** What if the excavation damage occurs on an excavation with no ticket? • **C.4.g.7** We have a lot of steel risers which can be tightened to eliminate leaks. We have not reported these on Form 7100 in PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING YEAR in the past. Are these leaks considered reportable leaks per DIMP, and should this threat be considered in a DIMP plan?

	[Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8] • Section 9 – Report Results
Guidance Information	1. The operator must have a written distribution integrity management plan (DIMP) that contains procedures for developing and implementing each requirement of §192.1007(g). The procedures must have adequate detail to clearly describe the manner in which each requirement will be met. The procedures need to provide a description of who, what, when, where, and how the operator will implement the elements. Operators must follow their procedures. The DIMP and any individual procedures documents should include management approvals, origin date, and the effective date of the last revision. For additional information, see the guidance section of §192.1005. 2. The operator must measure and report the following measures on an annual basis: (i) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause; (ii) Number of excavation damages; (iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center); (iv) Total number of leaks either eliminated or repaired, categorized by cause; 3. Evidence that the appropriate regulatory authority has been notified in accordance with the various requirements of the Rule must be retained by the operator, and the date of notification and the method of notification should be apparent. The use of electronic notification is preferred; therefore such electronic records are acceptable.
Examples of a Probable Violation	1. The operator does not have a procedure that covers the tasks being performed. 2. The operator fails to follow the written procedures. 3. The operator's procedures did not submit a report on the required performance measures. 4. The operator's procedures do not include all the measures specified by the Rule. 5. Operator failed to submit the required report on an annual basis pursuant to §191.11.
Examples of Evidence	1. Copies of an operator's procedure showing it does not meet the specified requirements. 2. Documented photographic evidence demonstrating the violation. 3. Documented oral and/or written statements from operator personnel. 4. Record demonstrating that required reporting was not performed in a timely manner.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§§192.1009, 191.12
Section Title	192.1009 What must an operator report when a mechanical fitting fails? 191.12 Distribution Systems: Mechanical Fitting Failure Reports
Existing Code Language	§192.1009 What must an operator report when a mechanical fitting fails? (a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak, on a Department of Transportation Form PHMSA F–7100.1–2. The report(s) must be submitted in accordance with §191.12. (b) The mechanical fitting failure reporting requirements in paragraph (a) of this section do not apply to the following: (1) Master meter operators; (2) Small LPG operator as defined in §192.1001; or (3) LNG facilities. §191.12 Distribution Systems: Mechanical Fitting Failure Reports Each mechanical fitting failure, as required by §192.1009, must be submitted on a Mechanical Fitting Failure Report Form PHMSA F–7100.1– 2. An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year (for example, all mechanical failure reports for calendar year 2011 must be submitted no later than March 15, 2012). Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to the State pipeline safety authority if a State has obtained regulatory authority over the operator's pipeline.
Origin of Code	192-116. 76 FR 5494, Feb. 1, 2011
Last Amendment	192-116, 76 FR 5494, Feb 1, 2011
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**<u>Advisory Bulletin ADB-12-07 - Issued June 11, 2012</u>** PHMSA is issuing an Advisory Bulletin to provide clarification to owners and operators of gas distribution pipeline facilities when completing the Mechanical Fitting Failure Report Form, PHMSA F 7100.1–2.
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 1 Plastic Pipe Reporting. Page 63907 Addressed in MFFR Final Rule preamble in Federal Register / Vol. 76, No. 21 / Tuesday, February 1, 2011 / Rules and Regulations at: • Pages 5494-5500

	[Distribution Integrity Management FAQs](#) • **C.5.1** Why is PHMSA collecting data about mechanical fitting failures? • **C.5.2** Do States already collect the type of information that is to be collected for mechanical fitting failures? • **C.5.3** Should both steel and plastic mechanical fitting failures be reported? How about the different styles of plastic mechanical fittings? Do mechanical fitting failures in cast iron systems need to be reported? • **C.5.4** Since there is a new form for mechanical fitting failures which result in a hazardous leak, do these failures still need to be reported under Part C of the Annual Report? • **C.5.5** If aboveground mechanical fitting failures are hazardous but repaired do they need to be reported? • **C.5.6** What are the expectations of operators in determining a cause for mechanical fitting failures which result in a hazardous leak?
Guidance Information	1. Operators must submit a Mechanical Fitting Failure Report Form PHMSA F–7100.1– 2 for each mechanical fitting failure which result in a hazardous leak. 2. Mechanical fitting failures which result in a hazardous leak may be submitted throughout the year or at one time prior to March 15th for the previous calendar year. An operator's procedure should describe or reference the methodology or process used to collect the mechanical coupling failure data for submission. 3. §192.1009 requirements do not apply to master meter operators or small LPG operators as defined in §192.1001.
Examples of a Probable Violation	1. The operator's DIMP does not address submitting information about mechanical fitting failures which result in hazardous leaks. 2. Apparent cause analysis was not adequately integrated into the IM program. 3. The appropriate actions were not specified to prevent recurrence of a problem that could lead to an integrity concern. 4. Operator did not report hazardous mechanical fitting failures, as appropriate.
Examples of Evidence	1. Copies of an operator's procedure showing it does not meet the specified requirements. 2. Documented photographic evidence demonstrating the violation. 3. Documented oral and/or written statements from operator personnel. 4. Records identifying mechanical fitting failures resulting in hazardous leaks that were not included in the reporting performed by the operator.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1011
Section Title	What records must an operator keep?
Existing Code Language	An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 11: Required documentation. Page 63915. Proposed documentation requirements were seen as unreasonably burdensome. In particular, the proposed requirements to document "all" decisions and changes related to a distribution integrity management (IM) program and to keep all related records for the life of the pipeline were seen as unreasonable. PHMSA has removed this list of documents and simplified the language of the regulation to require operators to maintain documentation demonstrating compliance. Distribution Integrity Management FAQs • **C.6.1** What records does an operator need to maintain to demonstrate compliance with Subpart P? • **C.6.2** Must I retain all records I consider in developing my DIMP under §192.1011? • **C.6.3** Am I required to submit my DIMP Plan to any Federal or State Regulator?
Guidance Information	1. Operators are required to maintain records that demonstrate compliance with the DIMP Rule for a minimum of 10 years, including superseded copies of the DIMP. An operator's procedure must require retention of records for a minimum of 10 years.

2. Records demonstrating compliance must be available for review during an inspection. These records must include baseline determinations and results for performance measures. Operators must be able to demonstrate that data was collected and results were reviewed to evaluate effectiveness of performance measures to support any actions taken or not taken.
3. Numerous records are generated as a result of Distribution Integrity Management Program. To the extent that these records demonstrate compliance with Rule requirements, they must be maintained by the operator such that they are readily retrievable, protected from damage, and secured sufficiently to prevent unauthorized use.
4. The rule does not list specific records that must be maintained, but examples of records demonstrating compliance may include:
    a. A written integrity management program
    b. Knowledge of the system documents
    c. Threat identification and risk assessment documentation
    d. Measures to address risk documentation
    e. Performance measures used to evaluate the effectiveness of risk mitigation measures documentation
    f. Records documenting performance of periodic evaluations of the DIMP program.
    g. Documentation of Notifications to PHMSA or State/Local Regulatory Agencies.
5. For records such as worksheets, memoranda or notes, these documents should be retrievable from a central location to the extent practicable, as opposed to being retained exclusively by individuals without record storage responsibilities. Since many records must be retained for the life of the pipeline, this suggests that records be kept in some sort of formalized or structured record-keeping system, as opposed to individual working files. The procedure should include the document location within the operator's facilities.
    a. As an alternative to each procedure specifying recordkeeping requirements, a single procedure that specifies all recordkeeping requirements would be considered sufficient programmatic control.
    b. Records retained should be in good condition, legible, readily retrievable, properly secured, and properly completed.
    c. Any procedures or guidance for threat identification and risk assessment must be retained, as well as the results of the process.
    d. Periodic updates to risk assessment documentation would also be expected in program files include supporting records such as meeting minutes of subject matter expert reviews where conclusions are drawn.
    e. The Rule does not require that documents to support any decision, analysis, and process developed and used to implement and evaluate each element of the integrity management program be maintained, but they are useful.
    f. This set of documents includes those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

	6. An operator must maintain the required records and superseded copies for 10 years. Earlier revisions to the program should be included in document files as archived information. Evidence must be included as to the effective date of any and all revisions.
Examples of a Probable Violation	1. Process/procedure did not require that all required records be maintained for the ten year minimum requirement. 2. The operator did not have a procedure specifying that copies of superseded integrity management plans will be maintained for at least 10 years. 3. The operator did not keep the required records or other documentation for the specified time period. 4. The operator did not keep the superseded integrity management plans for the specified time period. 5. The operator does not have records or other documentation to support compliance with the requirements of §192.1011. 6. The operator has records or other documentation to support the above requirements but the records or other documentation are insufficient to prove compliance.
Examples of Evidence	1. Copies of the applicable pages of the operator's DIMP showing that the procedure is not documented, is inadequate. 2. Absence of or insufficient records demonstrating that the operator cannot produce documentation that demonstrates compliance. 3. Absence of the superseded DIMP(s). 4. Documented photographic evidence demonstrating the violation. 5. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1013
Section Title	When may an operator deviate from required periodic inspections under this part?
Existing Code Language	(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this part on the basis of the engineering analysis and risk assessment required by this subpart. (b) An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety. (c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 6: Alternative Intervals. Page 63910 Distribution Integrity Management FAQs • **C.7.1** How can operators use their DIMP programs to justify reductions in other periodic test and inspection requirements? • **C.7.2** What will PHMSA (or States) require for proposals for alternate inspection intervals?
Guidance Information	1. Part 192 requires Distribution Operators to perform a number of inspections at specified intervals that include, but are not limited to: a. Part 192.465: CP Testing, Rectifier Inspection b. Part 192.465(e): Evaluate pipelines w/no CP c. Part 192.481: Atmospheric Corrosion Control Monitoring d. Part 192.723: Leak Surveys

	e. Part 192.739: Pressure Limiting Device Testing f. Part 192.747: Emergency Valves g. Part 192.749: Vault Inspections h. Part 192.721: Main Patrolling 2. A fundamental premise of risk management is reallocation of resources from activities that have a lesser effect on risk to activities that can have a greater impact. The intervals specified for required inspections in 192 are not risk based. They were set based on judgment and experience. An operator's risk assessment may show that some of these inspections have little effect on reducing risk, while resources conducting those inspections could be used for other activities that could have a significant impact on reducing risk. This regulation allows this type of resource reallocation to occur. 3. Changes to intervals required under this provision are not waivers or special permits. 192.1013 allows, by rule, changes to the intervals with approval by the Administrator of PHMSA or the appropriate state regulatory agency. 4. PHMSA/States may impose additional requirements as part of approving an application for alternative intervals. If that is done, the additional requirements become binding and the operator may be cited for failure to comply with them. Failure to comply could also result in the regulating authority rescinding its approval for alternative intervals.
Examples of a Probable Violation	1. Operator has implemented alternative intervals for one or more Part 192 requirements without obtaining approval of the regulating authority. 2. Operator is conducting required inspections at an interval that differs from the alternative interval approved by the regulating authority. 3. Operator is not complying with additional requirements imposed by the regulating authority as part of its approval of alternative intervals. 4. The regulating authority has rescinded approval for alternative intervals but the operator has not modified its procedures and practices to return to the interval specified in Part 192.
Examples of Evidence	1. Copy of letter/order from the regulating authority approving alternative intervals or lack thereof 2. Copies of procedures specifying different alternative intervals than those approved by the regulating authority. 3. Records indicating that inspections have been conducted at intervals greater than the alternative approved by the regulating authority. 4. Absence of and/or insufficient records demonstrating that the operator cannot produce documentation that demonstrates compliance. 5. Documented photographic evidence demonstrating the violation. 6. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(a)
Section Title	What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	(a) *General.* No later than August 2, 2011 the operator of a master meter system or a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. * * * * *
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 7: IM requirements for master meter and LPG operators. Page 63912 • Comment Topic 11: Required documentation. Page 63915 Distribution Integrity Management FAQs • **B.4.1** What is SHRIMP? (Simple, Handy, Risk-based Integrity Management Plan) • **B.4.2** Is there a threshold size of an operator's distribution system above which the SHRIMP tool should not be used? • **B.4.3** Will my plan be in compliance if I use SHRIMP? • **C.4.2** Can the DIMP plan incorporate by reference the operator's procedures from their other manuals or plans? • **C.7.1** How can operators use their DIMP programs to justify reductions in other periodic test and inspection requirements? • **C.7.2** What will PHMSA (or States) require for proposals for alternate inspection intervals? • **C.8.1** Are all LPG operators and natural gas operators, regardless of the size of their distribution system, subject to the DIMP regulation? • **C.8.3** What do master meter and small LPG operators need to have implemented by August 2, 2011?

	[Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8] • Section 1 Introduction 1.1-1.3 • Section 2 Elements of a Distribution Integrity Management Plan 2.1-2.2 • Section 10 Sample DIMP Approaches 10.1-10.2 [Gas Distribution Integrity Management Program: Resources] • DIMP Inspection Forms • Technical Reports • Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators • Plastic Piping Data Collection Initiative • Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 Distribution Management Integrity Program • SHRIMP - Simple Handy Rule based Integrity Management Plan • Industry Associations • Excavation Damage Prevention Organizations
Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis. 2. The written DIMP must include the date the DIMP was written and implemented, the effective date, and a revision history. 3. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure. *4.* Many operators use commercially-available products to develop their DIMP (e.g., APGA SIF's Simple, Handy, Rule-based Integrity Management Plan – SHRIMP). Most DIMPs developed using commercial products require customization to reflect the operator's unique circumstances and procedures. *Guidance specific to an operator who transfers pipeline assets to another operator but retains responsibility, by contract, for maintenance and distribution integrity management activities.* 1. Which operator is accountable for implementing the DIMP? OPS and the States inspect operators for compliance with the pipeline safety regulations. An 'operator' is defined in 49 C.F.R. §192.3 as "a person who engages in the transportation of *gas*". A 'person' is further defined as an

	individual or firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof. If an operator retains responsibility for operations and maintenance activities including integrity management, then that operator must comply with DIMP.
Examples of a Probable Violation	1. The operator does not have a DIMP written and implemented by August 2, 2011. 2. The operator does not address LPG or other types of gas transported when applicable. 3. There is ambiguity or confusion as to which pipeline system the DIMP address. 4. The DIMP does not contain the necessary mechanisms or procedures to demonstrate that the DIMP was written and is being implemented. 5. The DIMP does not include all pipe and appurtenances. 6. A new system was put into operation and service without a written DIMP. 7. An operator who acquired an existing system and did not continue operations under the existing DIMP or did not incorporate the acquired assets into its DIMP within one year.
Examples of Evidence	1. Copies of the applicable pages of the DIMP showing that the operator has not clearly stated that the DIMP was written and implemented by August 2, 2011. 2. Copies of the applicable pages of the DIMP showing that the operator has not clearly stated the type(s) of gas are transported. 3. Copies of the applicable pages of the DIMP showing that the operator has not clearly stated the system which the DIMP covers. 4. Documented photographic evidence demonstrating the violation. 5. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(b)(1)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements: * * * * * (1) *Knowledge.* The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 20: Knowledge of pipeline. a. Environmental factors, Page 63919 Distribution Integrity Management FAQs • **C.4.a.1** The rule requires that an operator know its system. Must an operator excavate simply to gather information about parts of its system where it may not now have complete knowledge? • **C.4.a.2** There are some characteristics about an operator's system that may not be known during the development of the IM plan. What are PHMSA's expectations for filling those voids? • **C.4.a.3** Who qualifies as a "subject matter expert"? • **C.4.a.4** What data will be required to be collected for new gas pipelines going in the ground? • **C.4.a.5** What comprises "reasonably available" information? • **C.4.a.6** Must an operator's plan include the sources used to demonstrate an understanding of its gas distribution system?

	Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 3 – Knowledge
Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis. 2. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure. 3. An operator must have knowledge of its gas distribution system including, but not limited to, the following: location, material composition, piping sizes, joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, history, operating experience performance data, condition of system, and any other characteristics noted by the operator as important to understanding its system. This information may be obtained from sources including system maps, construction records, work management system(s), geographic information system(s), corrosion records, and personnel who have knowledge of the system (Subject Matter Experts). 4. The operator must have documented mechanisms or procedures to adequately address the gathering of information to demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipe-line. 5. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities). 6. The DIMP must list the names of the operator specific information sources, not generic terms such as O&M documents. 7. Some historical data may be no longer applicable to the current condition of the pipeline system. If the pipe was replaced, the data about the previous pipe may no longer be relevant. Such data may be relevant where the circumstances (e.g., construction practices, coatings, backfill materials, pipe materials, environmental conditions) of the pipe prior to replacement exist elsewhere and are relevant to existing risks in the operator's system. For example, if bare steel pipe has been replaced, but some bare steel still exists in the system, then data concerning the replaced pipe may still be relevant.

	8. Operators who transport gases other than natural gas need to state in their DIMP how the characteristics of the gas impact the threats and risk and include the differences from natural gas. 9. For data identified by the operator as needed for a threat identification and risk evaluation, there must be a process to identify facilities for which records are missing, inaccurate, or incomplete. Verify that the operator has checked the data for accuracy and completeness. 10. Collecting additional data and improving existing data is only required to occur as part of normal pipeline activities and over time. There must be a method for the people performing normal pipeline activities to know what additional data is needed.
Examples of a Probable Violation	1. The operator does not have a mechanism or procedure that covers the tasks being performed. 2. The operator fails to follow the written mechanism or procedures. 3. Operator did not demonstrate that they have looked at all available source records to find information from past design, operations, or maintenance such as coating, material, etc. 4. Operator did not specifically list which documents were used to assemble knowledge of its system. 5. Operator does not gather or use reasonably available data on the entire pipeline that could be relevant to performing their threat assessment, risk evaluation or as needed to group like facilities. 6. There is no mechanism or procedure for identifying needed missing, inaccurate or incomplete data. 7. The operator has not identified missing, inaccurate or incomplete data. 8. Operator did not collect data as specified in the mechanism or procedure.
Examples of Evidence	1. Copies of the applicable pages of the DIMP showing that: a. The operator has not clearly stated the documents used to develop knowledge of the system. b. The list of documents used to develop knowledge of the system is inadequate in identifying design, operating, or environmental characteristics of the pipeline system. 2. Copies of applicable pages of the DIMP showing that the DIMP is not detailed enough for an inspector to make a reasonable determination as to the accuracy and thoroughness of the process. 3. Copies of the applicable pages of the operator's DIMP showing that the required regulations or provisions are not documented or that the records or other documentation is insufficient to prove compliance with the intended regulation or provision. 4. Copies of the applicable pages of the operator's DIMP showing that the required data collection and utilization of the data is not in the DIMP. 5. Documented photographic evidence demonstrating the violation. 6. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(b)(2)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements: * * * * * (2) *Identify threats.* The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**<u>Advisory Bulletin ADB-13-04 – Issued August 22, 2013</u>** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. **<u>Advisory Bulletin ADB-13-03: Correction – Issued October 31, 2013</u>** PHMSA is issuing an Advisory Bulletin to remind owners and operators of liquefied petroleum gas (LPG) and utility liquefied petroleum gas (utility LP-Gas) plants that although they must follow the American National Standards Institute/National Fire Protection Association (ANSI/NFPA) standards 58 or 59, they must also follow certain sections and requirements of Part 192. **<u>Advisory Bulletin ADB-13-02 – Issued July 12, 2013</u>** PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in case of flooding. **<u>Advisory Bulletin ADB-13-04 – Issued August 22, 2013</u>** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a

	dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. **<u>Advisory Bulletin ADB-11-05 – Issued August 26, 2011</u>** PHMSA advisory to remind owners and operators of gas and hazardous liquid pipelines of potential for damage to pipeline facilities caused by the passage of Hurricanes. In addition, mentions IM obligations under 195.452 **<u>Advisory Bulletin ADB-12-05 – Issued March 20, 2012</u>** PHMSA urges owners and operators to conduct a comprehensive review of their cast iron distribution pipeline systems and replacement programs and to accelerate pipeline repair, rehabilitation, and replacement of aging and high-risk pipe. In addition ADB notes regulation requirement for natural gas distribution companies to develop DIMP for pipelines owned, operated or maintained.
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 7: IM requirements for master meter and LPG operators. Page 63912 Distribution Integrity Management FAQs • **C.4.b.1** Must an operator use a computer-based risk analysis model? • **C.4.b.2** Must each of the 8 threats be considered for every pipeline type? • **C.4.b.3** The DIMP requirements include knowing the condition of facilities that are at risk for potential damage from external sources. Cross bores of gas lines in sewers have been reported at 2-3 per mile in high risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in the proximity of each other. Does the potential for cross bore of sewers resulting in gas lines intersecting with sewers need to be determined? • **C.4.b.4** Are pipeline “overbuilds” a threat? Should the “other concerns” threat category contain pipeline overbuilds (building put over a pipeline)? • **C.4.b.5** We used leak causes which we have experienced in the past to identify threats. For example, washouts in our system have not caused leaks in the past so washouts were not identified as a threat. Should washouts be classified as a potential threat due to the possibility of coating damage? • **C.4.b.6** Since we have not experienced any issues with pre 1973 Aldyl "A” pipe in the past, we did not subdivide plastic pipe in our risk evaluation. It is a potential threat to us only because of other operators' experience. Should we have treated it as an applicable threat? • **C.4.b.7** Must I consider historical leak data after a section of pipeline has been replaced? • **C.4.b.8** We often replace a section of pipeline rather than repairing individually the leaks in that section. In this case, must we record the number and grade of leaks?

	• **C.4.b.9** We are experiencing problems in ranking potential threats since some of the low frequency events have not occurred on our systems, to date. We are concerned about mixing apples and oranges by assigning a frequency or probability to a threat that has not occurred and ranking it along with events that do have frequency. How should we account for low or no frequency threats in evaluating and ranking risks? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 4 - Identify Threats • Table 4.1 Sample Threat Identification Method
Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the <u>mechanisms</u> or <u>procedures</u> the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis. 2. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure. 3. After characterizing its system, the operator must identify which threats are relevant to the different distribution segments. The process must meet the need of establishing a realistic identification of the threats and a determination of whether their frequency and level of significance require a response that goes beyond normal operating practices. 4. Operators must consider failures without a release as potential threats, when appropriate. 5. The operator must determine for each facility grouping which, if any, of the 7 primary or subcategory threats could affect the current or future integrity of that facility grouping. 6. Even if an operator concludes that a particular threat is not applicable to sections of its pipeline, the basis for drawing such conclusions must be documented. Operators may not discount or eliminate any existing or potential threat for a subsystem without an adequate basis for doing so. This basis must consider pipeline failure history, design, manufacturing, construction, operation, and maintenance. The reasons for excluding pipe must be documented in the operator's IM program 7. If data used for threat identification and categorization are insufficient or suspect, each threat covered by the missing or insufficient data is assumed to apply to the entire group being evaluated until the additional information is incorporated into the threat assessment. Unavailability of information is not

	justification for exclusion of a threat. Where data are missing or insufficient, conservative assumptions should be used in the risk assessment. Records must be maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered. 8. It may also be appropriate to subdivide threats. For example, consider atmospheric corrosion of aboveground pipe and external corrosion of buried pipe separately. Another example would be subdividing out known problem materials. 9. Excavation damage must be included in the threats considered in the DIMP, even if the operator has good external damage experience and a thorough damage prevention program. It is not acceptable for an operator to say that this threat is dealt with outside of DIMP and therefore need not be included. 10. Potential threats include threats where the operator has not experienced a leak (i.e., release of gas) but they have conditions conducive to the threat (e.g. atm. corrosion, hurricanes, flooding, excavation damage, materials with known integrity issues). Examples include: a. Trenchless technology used in the area – unknowingly bored thru sewer or water lines b. Future utility/road improvement projects c. Discovery of a material not previously known to be in the system d. Customers built structures over existing pipelines e. Overpressurization events f. Instances of pipe damage (including damage to tracer wire) that did not result in a release g. Pipe materials susceptible to brittle failure modes 11. Possible sources include past O&M procedures, purchase orders, material lists from old field orders or standards, and information from industry sources (e.g., plastic pipe data committee) or PHMSA Advisory Bulletins. Information should include for example, past continuing surveillance records (192.613).
Examples of a Probable Violation	1. The operator does not have a mechanism or procedure that covers the tasks being performed. 2. The operator fails to follow the written mechanism or procedures. 3. The mechanisms or procedures do not include a review of the 7 primary threats. 4. All of the 7 primary threats required by the rule were not adequately considered and/or evaluated 5. Multiple threats from the different 7 primary threat categories were not adequately evaluated 6. Specific threats eliminated from consideration without adequate justification 7. Operator does not use relevant operating and maintenance records in evaluating each threat. 8. Elimination of a threat is not sufficiently justified or documented. 9. Mechanism or procedure did not adequately describe the requirements for identifying and evaluating threats 10. Operator did not use reasonable or appropriate subdivision of threats 11. The mechanism or procedure did not include a review of the potential threats. 12. Operator did not use all reasonably available records.

Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate mechanisms or procedures. 2. Reasonably available external information (e.g., Advisory Bulletin) identifying a threat applicable to the operator's system that was not considered in developing the DIMP. 3. Documented photographic evidence demonstrating the violation. 4. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(b)(3)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	(b) *Elements*. A written integrity management plan must address, at a minimum, the following elements: * * * * * (3) *Rank risks*. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 22: Risk assessments. Page 63920 Distribution Integrity Management FAQs • **C.4.c.1** What are the key things an operator should be focusing on when developing an effective risk assessment methodology? • **C.4.c.2** From which date are operators required to collect data for their plan? • **C.4.c.3** How are newly identified threats to the system's integrity expected to be handled in an operator's DIMP plan? • **C.4.c.5** Do multiple threats need to be considered for each facility grouping? Do all threats need to be in one relative risk ranking? • **C.4.c.6** What is expected of multi-state operator in regards to a risk ranking? • **C.4.c.7** We plan to perform a risk ranking by state. Regardless of the outcome of the risk ranking, we will not decrease the historical level of expenditures in each state. However, a system wide risk ranking will be used to determine where expenditures beyond historical levels will be allocated. Does that meet the intent of the state by state risk ranking? • **C.4.b.9** We are experiencing problems in ranking potential threats since some of the low frequency events have not occurred on our systems, to date. We are concerned about mixing apples and oranges by assigning a frequency or probability to a threat that has not occurred and ranking it along with

	events that do have frequency. How should we account for low or no frequency threats in evaluating and ranking risks? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 5 – Evaluate and Rank Risk

Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis.
	2. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure.
	3. Once threats have been identified, the operator must develop a method to assess and prioritize the associated risks in order to address those of greatest concern first. In performing a risk analysis, it is important to note that risk is the likelihood of an event occurring times the consequence of that event. An event that is highly likely and also has a high public safety consequence constitutes an event of greatest concern. An unlikely event having minimal consequence may not justify extraordinary precautions. An unlikely event that could have very high consequences may justify additional precautions. Distribution incidents, (as defined in 49 CFR 191, Transportation of Natural and Other Gas By Pipeline: Annual Reports, Incident Reports, and Safety-Related Condition Reports, and contained in the PHMSA incident data base) often are events that are of low likelihood but of high consequence.
	4. The operator must identify both the likelihood (frequency) and the consequences (potential impact) of failures due to each threat/subcategory of threat for each system to determine the relatively risk. When risk reaches a threshold set by the operator measures to reduce risk may be needed to address the threat.
	5. It is inadequate for an operator to conclude that a pipeline is not subject to any particular threat or threats, based solely on the fact that it has not experienced a pipeline failure that has been attributed to the threat(s). They also must consider the potential threat.
	6. Examples of Likelihood factors to be considered:
	    a. Leaks per number of services (based on size of operator)
	    b. Amount of construction activity in area
	    c. Number of hits per unit locate tickets

	7. Examples of Consequence factors to be considered: a. operating pressure b. population density (“downtown” versus rural) c. impact of loss of supply d. number of customers affected e. proximity to structures and critical facilities (e.g. schools and hospitals) f. proximity to known groups of people with limited mobility (usually institutionalized) 8. The operator may employ various means to achieve validation. Elements of validation may include: a. Team review of results b. Subject Matter Expert reviews 9. The operator must have a mechanism or procedure for validating the results of the risk analysis process. The results generated by the model should agree with the consensus of the validation group. If the analysis results do not identify known risk factors, the evaluation model/method should be questioned, analyzed, and if necessary, revised.
Examples of a Probable Violation	1. The operator does not have a mechanism or procedure that covers the tasks being performed. 2. The operator fails to follow the written mechanism or procedures. 3. Operator did not perform a risk evaluation to estimate the relative importance of each identified threat 4. A comprehensive risk analysis process was not adequately developed 5. All portions of pipelines were not included in the risk analysis 6. The process did not adequately consider unique risk factors when using a "standard" risk model 7. The risk analysis process was not adequately documented 8. The risk analysis process did not adequately consider all identified risks 9. Operator-specific leak/failure history and other operating experience were not adequately considered in the in risk analysis 10. Poor quality data was used in the risk analysis 11. The basis for risk model scores was not adequately documented 12. Operator did not validate the results of the risk evaluation. 13. Operator history is not consistent with the output of the risk evaluation model. 14. Information provided by validation team members do not concur with results. 15. The operator has no documentation validating the ranking results. 16. Mechanism(s) or procedure(s) do not include sufficient detail and clarity to allow anyone required to use them to perform the task.
Examples of Evidence	1. Copies of the applicable pages from the operator’s DIMP which demonstrate inadequate procedures. 2. Documented oral and/or written statements from operator personnel. 3. Printout of operators risk ranking results. 4. Portions of the documentation of a commercial product that demonstrate it should not have been used in the manner the operator used it. 5. Documented photographic evidence demonstrating the violation. 6. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(b)(4)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	* * * * * (b) *Elements*. A written integrity management plan must address, at a minimum, the following elements: * * * * * (4) *Identify and implement measures to mitigate risks*. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline. * * * * *
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 14: Leak monitoring. Page 63917 • Comment Topic 16: IM program evaluation and improvement. Page 63918 • Comment Topic 23: Performance measures. Page 63922 Distribution Integrity Management FAQs • **C.4.d.1** Must an operator implement additional or accelerated actions to reduce risk from its pipeline? • **C.4.d.2** How will small operators, with limited staff, be able to implement the requirements for risk analysis and selection of risk control measures? • **C.4.d.3** If an operator already has a leak management program, does the operator have to implement a new program in response to this regulation? • **C.4.d.4** Why not simply require operators of gas distribution pipelines to replace old pipe? • **C.4.d.5** What kind of issues should an operator focus on in addressing the threat of Excavation Damage as part of its DIMP Plan?

	• **C.4.d.6** In order to eliminate the need for a leak management program, how quickly would an operator need to repair all leaks? • **C.4.d.7** Can the installation of excess flow valves be a method to mitigate risks? • **C.4.d.8** What criteria should an operator use to identify when a measure to reduce risk is needed? • **C.4.d.9** Do all actions operators take to reduce risk need to be included in their DIMP plan? • **C.4.d.10** We have heard that operators will be required to implement specific measures to reduce risk. Can you describe the required actions? • **C.4.d.11** How can an operator demonstrate that their leak management program is effective? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 6 – Identify and Implement Measures to Address Risks
Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis. 2. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure. 3. The design and operation of distributions systems is so diverse that no single risk control method is appropriate in all cases. 4. Risk can be reduced by implementing risk control practices that decrease the likelihood of the event occurring, or mitigate the consequence of the event. In considering gas distribution systems, it is essential to remember that the consequences of a failure in a distribution system may take a protracted period of time to develop. During this period of time, certain techniques can be used to detect the failure and actions can be taken to address the failure before it produces an incident. 5. The process for identifying additional measures is based on identified threats to each pipeline segment and the risk analysis. Clearly, facilities and groups of facilities that represent the highest risk are the most important candidates for measures to reduce risk. There is significant difference in requirements for MM and small LPG Operators versus operators under the §192.1005 requirements as this code section does not require measures to include an effective leak management program.

	6. Operators must have implemented and scheduled measures to address the prominent risks identified in their risk evaluation by August 2, 2011 as a DIMP was to have been developed and implemented by this date. Some measures can be implemented immediately. Others (e.g., pipe replacement) may require budget approval and allocation of resources; operators should have considered this and scheduled major measures appropriately in their DIMP. Operators are expected to promptly identify the need for measures in the event a new risk is identified. 7. The mechanisms or procedures must detail the basis for decisions and be documented as part of the operator's IM plan. Decisions include: a. Which measures to reduce risk to implement b. Schedule for implementation of the measure(s) to reduce risk c. Performance metrics for the measures to reduce risk 8. The operator must able to produce records demonstrating that a risk measure has been implemented or is scheduled to be implemented. Scheduled measures should be justified based on complexity of the implementation (considerations: budgetary constraints, procurement, need for additional resources, etc.). 9. For measures to reduce risk scheduled for future implementation the operator should have records which demonstrate actions are occurring to implement the measures according to the prescribed schedule. (e.g., budgeted, scheduled, preliminary actions completed).
Examples of a Probable Violation	1. The operator does not have a mechanism or procedure that covers the tasks being performed. 2. The operator fails to follow the written mechanism or procedures. 3. No mechanism or procedure is in place to identify additional measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure. 4. The mechanism or procedure does not identify the need for measures to reduce risk. 5. The mechanism or procedure does not require a schedule for implementation of measures to reduce risk. 6. The mechanism or procedure for identifying additional measures is not based on identified threats to each pipeline segment and the risk analysis. 7. The mechanism or procedure for evaluating additional preventive and mitigative measures does not adequately describe the method used to assure the appropriate selection of the risk mitigative measures intended to reduce risk for a specific threat. 8. The risk mitigative measures do not specifically address identified risk factors. 9. The DIMP does not provide a schedule for implementation of mitigative measures. 10. The impact of preventive or mitigative actions on risk was not adequately evaluated. 11. Measures to reduce risk have not been performed according to operator's guideline/procedure. 12. Operator has not identified measures to reduce risk when required by their risk evaluation. 13. Operator has not scheduled or obtained resources to perform measures to reduce risk.

Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate procedures. 2. Copies of the risk evaluation demonstrate that measures to reduce risk were needed but not scheduled. 3. Documented photographic evidence demonstrating the violation. 4. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(b)(5)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements: * * * * * (5) *Measure performance, monitor results, and evaluate effectiveness*. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Distribution Integrity Management FAQs • **C.4.e.1** Why has PHMSA selected the performance measures that it has for periodic reporting? • **C.4.e.2** Does every measure to address risk require a performance measure? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 7 – Measure performance, monitor results and evaluate effectiveness
Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis.

	2. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure. 3. The mechanism or procedure used by the operator must describe how they collect the data for the performance measure "number of leaks eliminated or repaired on its pipeline and their causes". The operator must identify how frequently they will monitor the measure. The operator must have documentation demonstrating that they are monitoring the performance measure "number of leaks eliminated or repaired on its pipeline and their causes".
Examples of a Probable Violation	1. DIMP does not contain a mechanism or procedure for how the operator monitors the performance measure "number of leaks eliminated or repaired on its pipeline and their causes". 2. Operator does not collect data to establish a baseline measurement or to monitor the performance measure "number of leaks eliminated or repaired on its pipeline and their causes". 3. Operator did not monitor the performance measure "number of leaks eliminated or repaired on its pipeline and their causes".
Examples of Evidence	1. Copies of the applicable pages from the operator's DIMP which demonstrate inadequate procedures. 2. Documented oral and/or written statements from operator personnel substantiating that data was not collected or monitored. 3. Documented photographic evidence demonstrating the violation.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(b)(6)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	(b) *Elements.* A written integrity management plan must address, at a minimum, the following elements: * * * * * (6) *Periodic evaluation and improvement.* The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 16: IM program evaluation and improvement. Page 63917 Distribution Integrity Management FAQs • **C.4.f.1** How often does an operator need to evaluate its program? • **C.4.f.2** What constitutes a periodic evaluation? Gas Piping Technology Committee (GPTC) Guide Material Appendix G-192-8 • Section 8 – Periodic Evaluation and Improvement
Guidance Information	1. Master Meter and Small LPG operators are treated differently in the DIMP Rule than larger operators. From 192.1001: *Integrity Management Plan* or *IM Plan* means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. For Master Meter and Small LPG operators, integrity management program must include the appropriate set of mechanisms or procedures to develop and implement each program element. The applicability of the word mechanisms for these operators is important as a synonym for mechanisms is processes. The operator may employ a written

	explanation of the process employed (mechanism) to develop and implement a required element that is less specific than a written procedure. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. The DIMP could be concise, but still must be sufficient for operator personnel to understand and implement the program on a consistent basis. 2. The operator may use a written explanation of the process employed to develop and implement a required element that is less specific than a written procedure. 3. Master meter and small LPG operator's systems are generally not complex. If there are no significant changes to the condition of the system, the DIMP may only need to be evaluated for improvements every 5 years. If changes occur in the factors affecting the risk of failure, a program evaluation should be conducted on a more frequent basis. 4. The evaluation of program effectiveness should include the following items to determine if modifications to the program need to be made: • Risk prioritization results • Risk control practices • Failure analysis results • Performance measures 5. The method of evaluation could range from a formal audit of the program to a simple review of the above items by a subject matter expert, based on the needs of the program. 6. Corrective actions to improve the integrity management program must be documented and are monitored for effectiveness. These reviews must examine the effectiveness of the measure to reduce risk and the performance measure with recommendations for improvement where necessary. Generic statements about implementing improvements are not acceptable.
Examples of a Probable Violation	1. DIMP did not state the frequency of program evaluation. 2. Procedure did not include the evaluation of performance measures and their effectiveness to determine if they are still appropriate or if they need to be adjusted. **Evaluation** 1. The operator does not have a mechanism or procedure that covers the tasks being performed. 2. The operator fails to follow the written mechanism or procedures. 3. Performance goals were not included in the procedure 4. An operator's DIMP evaluation process does not specifically address the means (methods) the operator implemented to track DIMP performance or the procedure does not have specific frequencies (time frames) at which the operator must track DIMP performance. 5. An operator's DIMP evaluation procedure does not assess whether the DIMP is effective in reducing risk. 6. An operator's DIMP evaluation process does not provide the operator information on implementing improvements in its DIMP effectiveness based on findings from the evaluation. 7. The operator's evaluation process is not based on sound and repeatable principles or is not sufficiently documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the process.

	Improvement 1. An operator did not change its DIMP, as required to address information obtained through annual reviews, program evaluations, or whenever any change occurs that would materially alter any of the elements in the DIMP. 2. An operator did not actually make the changes to the DIMP or did not implement the changes to the DIMP when and where the program evaluation identified changes were required. 3. An operator did not thoroughly document the changes including the purpose, content and date completed. 4. The process the operator describes in the procedure is not sufficiently documented so an inspector can make a reasonable determination as to the accuracy and thoroughness of the process. 5. Mechanism(s) or procedure(s) do not include sufficient detail and clarity to allow anyone required to use them to perform the task. **Implementation** 1. A DIMP program evaluation was not adequately performed and/or the results were not adequately documented 2. Adequate actions were not identified to improve the DIMP based on a review of the evaluation 3. Actions identified by the DIMP program evaluation were not adequately implemented 4. Response to performance measures indicating poor performance was inadequate
Examples of Evidence	1. Copies of the applicable DIMP pages supporting any of the violations discussed above either separately or in combination. 2. Copies of an operator's procedure showing it does not meet the specified requirements. 3. Documented photographic evidence demonstrating the violation. 4. Documented oral and/or written statements from operator personnel.
Other Special Notations	

Enforcement Guidance	Distribution Integrity Management Part 192
Revision Date	12/23/2013
Code Section	§192.1015(c)
Section Title	§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?
Existing Code Language	* * * * * (c) *Records.* The operator must maintain, for a period of at least 10 years, the following records: (1) A written IM plan in accordance with this section, including superseded IM plans; (2) Documents supporting threat identification; and (3) Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.
Origin of Code	192-113, 74 FR 63906, Dec. 4, 2009
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Addressed in DIMP Final Rule preamble in Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations at: • Comment Topic 11: Required documentation. Page 63915 Distribution Integrity Management FAQs • **C.4.g.1** When must operators start collecting and maintaining records with data needed for performance measures? • **C.4.g.3** Can PHMSA further define the number of excavation tickets on the new form? • **C.4.g.4** For municipal operators or joint utility operators, should the number of excavation tickets include all excavation tickets or just those sent to the gas department? • **C.4.g.5** Are multiple tickets for a single job counted as a single excavation ticket? • **C.4.g.6** What if the excavation damage occurs on an excavation with no ticket?

	• **C.4.g.7** We have a lot of steel risers which can be tightened to eliminate leaks. We have not reported these on Form 7100 in PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING YEAR in the past. Are these leaks considered reportable leaks per DIMP, and should this threat be considered in a DIMP plan? • **C.6.1** What records does an operator need to maintain to demonstrate compliance with Subpart P? • **C.6.2** Must I retain all records I consider in developing my DIMP under §192.1011? • **C.6.3** Am I required to submit my DIMP Plan to any Federal or State Regulator?
Guidance Information	1. Operators are required to maintain records that demonstrate compliance with the DIMP Rule for a minimum period of 10 years, including superseded copies of the DIMP. 2. Earlier revisions to the program must be included in document files as archived information. Documentation must be included as to the effective date of any and all revisions. 3. Numerous records are generated as a result of Distribution Integrity Management Program. To the extent that these records demonstrate compliance with Rule requirements, they are to be maintained by the operator such that they are readily retrievable, protected from damage, and secured sufficiently to prevent unauthorized use. 4. For records such as worksheets, memoranda or notes, these documents should be retrievable from a central location to the extent practicable, as opposed to being retained exclusively by individuals without record storage responsibilities. Since many records must be retained for the life of the pipeline, this suggests that records be kept is some sort of formalized or structured record-keeping system, as opposed to individual working files. The procedure should include the document location within the operator's facilities. a. As an alternative to each guideline/procedure specifying recordkeeping requirements, a single document that specifies all recordkeeping requirements would be considered sufficient programmatic control. b. Records retained should be in good condition, legible, readily retrievable, properly secured, and properly completed. c. Any procedures or guidance for threat identification and risk assessment must be retained, as well as the results of the process. d. Periodic updates to risk assessment documentation would also be expected in program files include supporting records such as meeting minutes of subject matter expert reviews where conclusions are drawn. e. The regulation does not require that documents to support any decision, analysis, and process developed and used to implement and evaluate each element of the integrity management program be maintained but they are useful. f. This set of documents includes those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

	5. The operator needs provisions in their written DIMP for capturing and retaining data about new pipeline installations. Data for new pipelines must include all the characteristics needed to identify threats and evaluate risks in the Operator's DIMP. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed. The operator could document this on a map or other drawings of their system. 6. Material is more than just "steel" or "plastic." It should include the specification, grade of steel or type of plastic, manufacturer, coating, etc. In accordance with the definition of "pipeline" in §192.3, this includes valves and other appurtenances through which gas flows.
Examples of a Probable Violation	1. The operator did not have a mechanism or procedure specifying that copies of superseded integrity management plans will be maintained for at least 10 years. 2. Operator does not have document(s) to support threat identification. 3. The operator did not keep the required records or other documentation for ten years. 4. The operator does not have records or other documentation to support any of the above requirements. 5. The operator has records or other documentation to support compliance with the above requirements. 6. Operator does not have document(s) demonstrating the material and location of facilities to the extent known prior to and installed after the effective date of their IM plan. 7. Procedures do not include a process to record the necessary data about new pipelines.
Examples of Evidence	1. Copies of an operator's mechanism or procedure showing it does not meet the specified requirements. 2. Copies of the applicable pages of the operator's DIMP showing that the required data collection and utilization of the data is not in the DIMP. 3. Documented photographic evidence demonstrating the violation. 4. Documented oral and/or written statements from operator personnel.
Other Special Notations	